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Small Signal Stability and Power System Oscillations

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9.1	Nature of Power System Oscillations	9-1
	Historical Perspective • Power System Oscillations Classified by Interaction Characteristics • Conceptual Description of Power System Oscillations • Summary on the Nature of Power System Oscillations	
9.2	Criteria for Damping	9-7
9.3	Study Procedure	9-7
9.4	Mitigation of Power System Oscillations	9-9
	Siting • Control Objectives • Closed-Loop Control Design • Input Signal Selection • Input-Signal Filtering • Control Algorithm • Gain Selection • Control Output Limits • Performance Evaluation • Adverse Side Effects • Higher-Order Terms for Small-Signal Analysis	
9.5	Higher-Order Terms for Small-Signal Analysis	9-13
9.6	Summary	9-14

9.1 Nature of Power System Oscillations

9.1.1 Historical Perspective

Damping of oscillations has been recognized as important in electric power system operations from the beginning. Before there were any power systems, oscillations in automatic speed controls (governors) initiated an analysis by J.C. Maxwell (speed controls were found necessary for the successful operation of the first steam engines). Apart from the immediate application of Maxwell's analysis, it also had a lasting influence as at least one of the stimulants to the development of very useful and widely used method by E.J. Routh in 1883, which enables one to determine theoretically the stability of a high-order dynamic system without having to know the roots of its equations (Maxwell analyzed only a second-order system).

Oscillations among generators appeared as soon as AC generators were operated in parallel. These oscillations were not unexpected, and in fact, were predicted from the concept of the power vs. phase-angle curve gradient interacting with the electric generator rotary inertia, forming an equivalent mass-and-spring system. With a continually varying load and some slight differences in the design and loading of the generators, oscillations tended to be continually excited. In the case of hydrogenerators, in particular, there was very little damping, and so amortisseurs (damper windings) were installed, at first as an option. (There was concern about the increased short-circuit current and some people had to be persuaded to accept them (Crary and Duncan, 1941).) It is of interest to note that although the only

significant source of actual negative damping here was the turbine speed governor (Concordia, 1969), the practical “cure” was found elsewhere. Two points were evident then and are still valid today. First, automatic control is practically the only source of negative damping, and second, although it is obviously desirable to identify the sources of negative damping, the most effective and economical place to add damping may lie elsewhere.

After these experiences, oscillations seemed to disappear as a major problem. Although there were occasional cases of oscillations and evidently poor damping, the major analytical effort seemed to ignore damping entirely. First using analog and then digital, computing aids analysis of electric power system dynamic performance was extended to very large systems, but still representing the generators (and, for that matter, also the loads) in the simple “classical” way. Most studies covered only a short time-period, and as occasion demanded, longer-term simulations were kept in bound by including empirically estimated damping factors. It was, in effect, tacitly assumed that the net damping was positive.

All this changed rather suddenly in the 1960s, when the process of interconnection accelerated and more transmission and generation extended over large areas. Perhaps, the most important aspect was the wider recognition of the negative damping produced by the use of high-response generator voltage regulators in situations where the generator may be subject to relatively large angular swings, as may occur in extensive networks. (This possibility was already well known in the 1930s and 1940s but had not had much practical application then.) With the growth of extensive power systems, and especially with the interconnection of these systems by ties of limited capacity, oscillations reappeared. (Actually, they had never entirely disappeared but instead were simply not “seen.”) There are several reasons for this reappearance:

1. For intersystem oscillations, the amortisseur is no longer effective, as the damping produced is reduced in approximately inverse proportion to the square of the effective external-impedance-plus-stator-impedance, and so it practically disappears.
2. The proliferation of automatic controls has increased the probability of adverse interactions among them. (Even without such interactions, the two basic controls—the speed governor and the generator voltage regulator—practically always produce negative damping for frequencies in the power system oscillation range: the governor effect, small and the AVR effect, large.)
3. Even though automatic controls are practically the only devices that may produce negative damping, the damping of the uncontrolled system is itself very small and could easily allow the continually changing load and generation to result in unsatisfactory tie-line power oscillations.
4. A small oscillation in each generator that may be insignificant may add up to a tie-line oscillation that is very significant relative to its rating.
5. Higher tie-line loading increases both the tendency to oscillate and the importance of the oscillation.

To calculate the effect of damping on the system, the detail of system representation has to be considerably extended. The additional parameters required are usually much less well-known than are the generator inertias and network impedances required for the “classical” studies. Further, the total damping of a power system is typically very small and is made up of both positive and negative components. Thus, if one wishes to get realistic results, one must include all the known sources. These sources include: prime movers, speed governors, electrical loads, circuit resistance, generator amortisseurs, generator excitation, and in fact, all controls that may be added for special purposes. In large networks, and particularly as they concern tie-line oscillations, the only two items that can be depended upon to produce positive damping are the electrical loads and (at least for steam-turbine driven generators) the prime mover.

Although it is obvious that net damping must be positive for stable operation, why be concerned about its magnitude? More damping would reduce (but not eliminate) the tendency to oscillate and the magnitude of oscillations. As pointed out above, oscillations can never be eliminated, as even in the best-damped systems the damping is small, which is only a small fraction of the “critical damping.” So the common concept of the power system as a system of masses and springs is still valid, and we have to

accept some oscillations. The reasons why the power systems are often troublesome are various, depending on the nature of the system and the operating conditions. For example, when at first a few (or more) generators were paralleled in a rather closely connected system, oscillations were damped by the generator amortisseurs. If oscillations did occur, there was little variation in system voltage. In the simplest case of two generators paralleled on the same bus and equally loaded, oscillations between them would produce practically no voltage variation and what was produced would principally be at twice the oscillation frequency. Thus, the generator voltage regulators were not stimulated and did not participate in the activity. Moreover, the close coupling between the generators reduced the effective regulator gain considerably for the oscillation mode. Under these conditions, when voltage-regulator response was increased (e.g., to improve transient stability), there was little apparent decrease of system damping (in most cases), but appreciable improvement in transient stability. Instability through negative damping produced by increased voltage-regulator gain had already been demonstrated theoretically (Concordia, 1944).

Consider that the system just discussed is then connected to another similar system by a tie-line. This tie-line should be strong enough to survive the loss of any one generator but rather may be only a small fraction of system capacity. Now, the response of the system to tie-line oscillations is quite different from that just described. Because of the high external-impedance seen by either system, not only is the positive damping by the generator amortisseurs largely lost, but also the generator terminal voltages become responsive to angular swings. This causes the generator voltage regulators to act, producing negative damping as an unwanted side effect. This sensitivity of voltage-to-angle increases as a strong function of initial angle, and thus tie-line loading. Thus, in the absence of mitigating means, tie-line oscillations are very likely to occur, especially at heavy-line loading (and they have on numerous occasions as illustrated in [Chapter 3](#) of CIGRE Technical Brochure No. 111 [1996]). These tie-line oscillations are bothersome, especially as a restriction on the allowable power transfer, as relatively large oscillations are (quite properly) taken as a precursor to instability.

Next, as interconnection proceeds another system is added. If the two previously discussed systems are designated A and B, and a third system, C, is connected to B, then a chain A-B-C is formed. If power is flowing $A \rightarrow B \rightarrow C$ or $C \rightarrow B \rightarrow A$, the principal (i.e., lowest frequency) oscillation mode is A against C, with B relatively quiescent. However, as already pointed out, the voltages of system B are varying. In effect, B is acting as a large synchronous condenser facilitating the transfer of power from A to C, and suffering voltage fluctuations as a consequence. This situation has occurred several times in the history of interconnected power systems and has been a serious impediment to progress. In this case, note that the problem is mostly in system B, while the solution (or at least mitigation) will be mostly in systems A and C. With any presently conceivable controlled voltage support, it would be practically impossible to maintain a satisfactory voltage solely in system B. On the other hand, without system B, for the same power transfer, the oscillations would be much more severe. In fact, the same power transfer might not be possible without, for example, a very high amount of series or shunt compensation. If the power transfer is $A \rightarrow B \leftarrow C$ or $A \leftarrow B \rightarrow C$, the likelihood of severe oscillation (and the voltage variations produced by the oscillations) is much less. Further, both the trouble and the cure are shared by all three systems, so effective compensation is more easily achieved. For best results, all combinations of power transfers should be considered.

Aside from this abbreviated account of how oscillations grew in importance as interconnections grew in extent, it may be of interest to mention the specific case that seemed to precipitate the general acceptance of the major importance of improving system damping, as well as the general recognition of the generator voltage regulator as the major culprit in producing negative damping. This was the series of studies of the transient stability of the Pacific Intertie (AC and DC in parallel) on the west coast of the U.S. In these studies, it was noted that for three-phase faults, instability was determined not by severe first swings of the generators but by oscillatory instability of the post-fault system, which had one of two parallel AC line sections removed and thus higher impedance. This showed that damping is important for transient as well as steady-state conditions and contributed to a worldwide rush to apply power system stabilizers (PSS) to all generator-voltage regulators as a panacea for all oscillatory ills.

But the pressures of the continuing extension of electric networks and of increases in line loading have shown that the PSS alone is often not enough. When we push to the limit that limit is more often than not determined by lack of adequate damping. When we add voltage support at appropriate points in the network, we not only increase its “strength” (i.e., increased synchronizing power or smaller transfer impedance), but also improve its damping (if the generator voltage regulators have been producing negative damping) by relieving the generators of a good part of the work of voltage regulation and also reducing the regulator gain. This is so, whether or not reduced damping was an objective. However, the limit may still be determined by inadequate damping. How can it be improved? There are at least three options:

1. Add a signal (e.g., line current) to the voltage support device control.
2. Increase the output of the PSS (which is possible with the now stiffer system), or do both as found to be appropriate.
3. Add an entirely new device at an entirely new location. Thus the proliferation of controls that has to be carefully considered.

Oscillations of power system frequency as a whole can still occur in an isolated system, due to governor deadband or interaction with system frequency control, but is not likely to be a major problem in large interconnected systems. These oscillations are most likely to occur on intersystem ties among the constituent subsystems, especially if the ties are weak or heavily loaded. This is in a relative sense; an “adequate” tie planned for certain usual line loadings is nowadays very likely to be much more severely loaded and, thus, behave dynamically like a weak line as far as oscillations are concerned, quite aside from losing its emergency pick-up capability. There has always been commercial pressure to utilize a line, perhaps originally planned to aid in maintaining reliability, for economical energy transfer simply because it is there. Now, however, there is also “open access” that may force a utility to use nearly every line for power transfer. This will certainly decrease reliability and may decrease damping, depending on the location of added generation.

9.1.2 Power System Oscillations Classified by Interaction Characteristics

Electric power utilities have experienced problems with the following types of subsynchronous frequency oscillations (Kundur, 1994):

- Local plant mode oscillations
- Interarea mode oscillations
- Torsional mode oscillations
- Control mode oscillations

Local plant mode oscillation problems are the most commonly encountered among the above and are associated with units at a generating station oscillating with respect to the rest of the power system. Such problems are usually caused by the action of the AVR of generating units operating at high-output and feeding into weak-transmission networks; the problem is more pronounced with high-response excitation systems. The local plant oscillations typically have natural frequencies in the range of 1–2 Hz. Their characteristics are well understood and adequate damping can be readily achieved by using supplementary control of excitation systems in the form of power system stabilizers (PSS).

Interarea modes are associated with machines in one part of the system oscillating against machines in other parts of the system. They are caused by two or more groups of closely coupled machines that are interconnected by weak ties. The natural frequency of these oscillations is typically in the range of 0.1–1 Hz. The characteristics of interarea modes of oscillation are complex and in some respects significantly differ from the characteristics of local plant modes (CIGRE Technical Brochure No. 111, 1996; Kundur, 1994; Rogers, 2000).

Torsional mode oscillations are associated with the turbine-generator rotational (mechanical) components. There have been several instances of torsional mode instability due to interactions with controls, including generating unit excitation and prime mover controls (Kundur, 1994):

- Torsional mode destabilization by excitation control was first observed in 1969 during the application of power system stabilizers on a 555 MVA fossil-fired unit at the Lambton generating station in Ontario. The PSS, which used a stabilizing signal based on speed measured at the generator end of the shaft, was found to excite the lowest torsional (16 Hz) mode. The problem was solved by sensing speed between the two LP turbine sections and by using a torsional filter (Kundur et al., 1981; Watson and Coultas, 1973).
- Instability of torsional modes due to interaction with speed-governing systems was observed in 1983 during the commissioning of a 635 MVA unit at Pickering “B” nuclear generating station in Ontario. The problem was solved by providing an accurate linearization of steam valve characteristics and by using torsional filters (Lee et al., 1985).
- Control mode oscillations are associated with the controls of generating units and other equipment. Poorly tuned controls of excitation systems, prime movers, static var compensators, and HVDC converters are the usual causes of instability of control modes. Sometimes it is difficult to tune the controls so as to assure adequate damping of all modes. Kundur et al. (1981) describe the difficulty experienced in 1979 in tuning the power system stabilizers at the Ontario Hydro’s Nanticoke generating station. The stabilizers used shaft-speed signals with torsional filters. With the stabilizer gain high-enough to stabilize the local plant mode oscillation, a control mode local to the excitation system and the generator field referred to as the “exciter mode” became unstable. The problem was solved by developing an alternative form of stabilizer that did not require a torsional filter (Lee and Kundur, 1986).
- Refer also to [Chapter 16](#).

Although all of these categories of oscillations are related and can exist simultaneously, the primary focus of this section is on the electromechanical oscillations that affect interarea power flows.

9.1.3 Conceptual Description of Power System Oscillations

As illustrated in the previous subsection, power systems contain many modes of oscillation due to a variety of interactions of its components. Many of the oscillations are due to generator rotor masses swinging relative to one another. A power system having multiple machines will act like a set of masses interconnected by a network of springs and will exhibit multiple modes of oscillation. As illustrated previously in [Section 9.1.1](#), in many systems, the damping of these electromechanical swing modes is a critical factor for operating the power system in a stable, thus secure manner (Kundur et al., 2004). The power transfer between such machines on the AC transmission system is a direct function of the angular separation between their internal voltage phasors. The torques that influence the machine oscillations can be conceptually split into synchronizing and damping components of torque (de Mello and Concordia, 1969). The synchronizing component “holds” the machines in the power system together and is important for system transient stability following large disturbances. For small disturbances, the synchronizing component of torque determines the frequency of an oscillation. Most stability texts present the synchronizing component in terms of the slope of the power-angle relationship, as illustrated in [Fig. 9.1](#), where K represents the amount of synchronizing torque. The damping component determines the decay of oscillations and is important for system stability following recovery from the initial swing. Damping is influenced by many system parameters, is usually small, and as previously described, is sometimes negative in the presence of controls (which are practically the only “source” of negative damping). Negative damping can lead to spontaneous growth of oscillations until relays begin to trip system elements or a limit cycle is reached.

[Figure 9.2](#) shows a conceptual block diagram of a power-swing mode, with inertial (M), damping (D), and synchronizing (K) effects identified. For a perturbation about a steady-state operating point, the modal accelerating torque ΔT_{ai} is equal to the modal electrical torque ΔT_{ei} (with the modal mechanical torque ΔT_{mi} considered to be 0). The effective inertia is a function of the total inertia of all machines participating in the swing; the synchronizing and damping terms are frequency dependent and are influenced by generator rotor circuits, excitation controls, and other system controls.

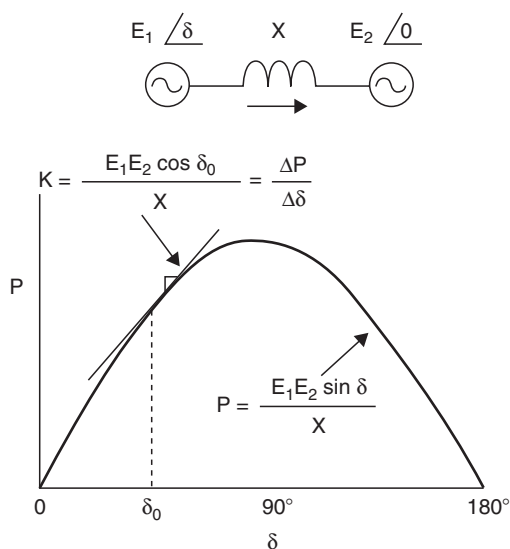
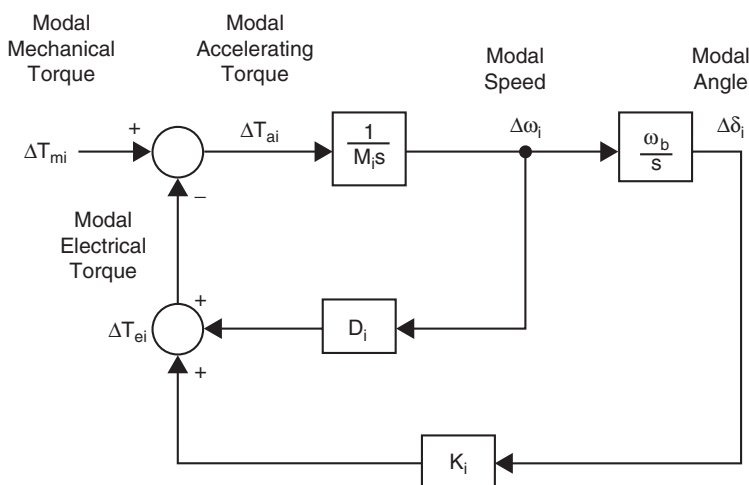


FIGURE 9.1 Simplified power-angle relationship between two AC systems.

9.1.4 Summary on the Nature of Power System Oscillations

The preceding review leads to a number of important conclusions and observations concerning power system oscillations:

- Oscillations are due to natural modes of the system and therefore cannot be eliminated. However, their damping and frequency can be modified.
- As power systems evolve, the frequency and damping of existing modes change and new modes may emerge.
- The source of “negative” damping is power system controls, primarily excitation system automatic voltage regulators.
- Interarea oscillations are associated with weak transmission links and heavy power transfers.
- Interarea oscillations often involve more than one utility and may require the cooperation of all to arrive at the most effective and economical solution.
- Power system stabilizers are the most commonly used means of enhancing the damping of interarea modes.



M_i = Modal Inertia

D_i = Modal Damping Coefficient

K_i = Modal Synchronizing Coefficient

ω_b = Base Frequency

ω_i = Swing Model Frequency $\sqrt{\omega_b K_i / M_i}$

FIGURE 9.2 Conceptual block diagram of a power-swing mode.

- Continual study of the system is necessary to minimize the probability of poorly damped oscillations. Such “beforehand” studies may have avoided many of the problems experienced in power systems (see Chapter 3 of CIGRE Technical Brochure No. 111, 1996).

It must be clear that avoidance of oscillations is only one of many aspects that should be considered in the design of a power system and so must take its place in line along with economy, reliability, security, operational robustness, environmental effects, public acceptance, voltage and power quality, and certainly a few others that may need to be considered. Fortunately, it appears that many features designed to further some of these other aspects also have a strong mitigating effect in reducing oscillations. However, one overriding constraint is that the power system operating point must be stable with respect to oscillations.

9.2 Criteria for Damping

The rate of decay of the amplitude of oscillations is best expressed in terms of the damping ratio ζ . For an oscillatory mode represented by a complex eigenvalue $\sigma \pm j\omega$, the damping ratio is given by

$$\zeta = \frac{-\sigma}{\sqrt{\sigma^2 + \omega^2}} \quad (9.1)$$

The damping ratio ζ determines the rate of decay of the amplitude of the oscillation. The time constant of amplitude decay is $1/|\sigma|$. In other words, the amplitude decays to $1/e$ or 37% of the initial amplitude in $1/|\sigma|$ seconds or in $1/(2\pi\zeta)$ cycles of oscillation (Kundur, 1994). As oscillatory modes have a wide range of frequencies, the use of damping ratio rather than the time constant of decay is considered more appropriate for expressing the degree of damping. For example, a 5-s time constant represents amplitude decay to 37% of initial value in 110 cycles of oscillation for a 22 Hz torsional mode, in 5 cycles for a 1-Hz local plant mode, and in one-half cycle for a 0.1-Hz interarea mode of oscillation. On the other hand, a damping ratio of 0.032 represents the same degree of amplitude decay in 5 cycles, for example, for all modes.

A power system should be designed and operated so that the following criteria are satisfied for all expected system conditions, including post-fault conditions following design contingencies:

1. The damping ratio (ζ) of all system modes oscillation should exceed a specified value. The minimum acceptable damping ratio is system dependent and is based on operating experience and/or sensitivity studies; it is typically in the range 0.03–0.05.
2. The small-signal stability margin should exceed a specified value. The stability margin is measured as the difference between the given operating condition and the absolute stability limit ($\zeta = 0$) and should be specified in terms of a physical quantity, such as a power plant output, power transfer through a critical transmission interface, or system load level.

9.3 Study Procedure

There is a general need for establishing study procedures and developing widely accepted design and operating criteria with respect to power system oscillations. Tools for the analysis of system oscillations, in addition to determining the existence of problems, should be capable of identifying factors influencing the problem and providing information useful in developing control measures for mitigation.

System oscillation problems are often investigated using nonlinear time-domain simulations as a natural extension to traditional transient stability analysis. However, there are a number of practical problems that limit the effectiveness of using only the time-domain approach:

- The use of time responses exclusively to look at damping of different modes of oscillation could be deceptive. The choice of disturbance and the selection of variables for observing

time-response are critical. The disturbance may not provide sufficient excitation of the critical modes. The observed response contains many modes, and poorly damped modes may not always be dominant.

- To get a clear indication of growing oscillations, it is necessary to carry the simulations out to 15 or 20 s or more. This could be time-consuming.
- Direct inspection of time responses does not give sufficient insight into the nature of the oscillatory stability problem; it is difficult to identify the sources of the problem and develop corrective measures.

Spectral estimation (i.e., modal identification) techniques based on Prony analysis may be used to analyze time-domain responses and extract information about the underlying dynamics of the system (Hauer, 1991).

Small-signal analysis (i.e., modal analysis or eigenanalysis) based on linear techniques is ideally suited for investigating problems associated with oscillations. Here, the characteristics of a power system model can be determined for a system model linearized about a specific operating point. The stability of each mode is clearly identified by the system's eigenvalues. Modeshapes and the relationships between different modes and system variables or parameters are identified using eigenvectors (Kundur, 1994). Conventional eigenvalue computation methods are limited to systems up to about 800 states. Such methods are ideally suited for detailed analysis for system oscillation problems confined to a small portion of the power system. This includes problems associated with local plant modes, torsional modes, and control modes. For very large interconnected systems, it may be necessary to use dynamic equivalents (Wang et al., 1997; Piwko et al., 1991). This can only be achieved by developing reduced-order power system models that correctly reflect the significant dynamic characteristics of the interconnected system.

For analysis of interarea oscillations in large interconnected power systems, special techniques have been developed for computing eigenvalues associated with a small subset of modes whose frequencies are within a specified range (Kundur, 1994). Techniques have also been developed for efficiently computing participation factors, residues, transfer function zeros, and frequency responses useful in designing remedial control measures (Martins et al., 1992, 1996, 2003). Powerful computer program packages incorporating the above computational features are now available, thus providing comprehensive capabilities for analyses of power system oscillations (CIGRE Technical Brochure No. 111, 1996; CIGRE Technical Brochure No. 166, 2000; Kundur, 1994; Semlyen et al., 1988; Wang et al., 1990; Kundur et al., 1990).

In summary, a complete understanding of power systems oscillations generally requires a combination of analytical tools. Small-signal stability analysis complemented by nonlinear time-domain simulations is the most effective procedure of studying power system oscillations. The following are the recommended steps for a systematic analysis of power system oscillations:

1. Perform an eigenvalue scan using a small-signal stability program. This will indicate the presence of poorly damped modes.
2. Perform a detailed eigenanalysis of the poorly damped modes. This will determine their characteristics and sources of the problem, and assist in developing mitigation measures. This will also identify the quantities to be monitored in time-domain simulations.
3. Perform time-domain simulations of the critical cases identified from the eigenanalysis. This is useful to confirm the results of small-signal analysis. In addition, it shows how system nonlinearities affect the oscillations. Prony analysis of these time-domain simulations may also be insightful (Hauer, 1991).

The IEEE Power Engineering Society Power System Dynamic Performance Committee has sponsored a series of panel sessions on small-signal stability and linear analysis techniques from 1998 to 2005, which can be found in the following: Gibbard, et al., 2001; IEEE PES, 2000; IEEE PES, 2002; IEEE PES, 2003; and IEEE PES, 2005. Further archival information can be found in IEEE PES, 1995.

9.4 Mitigation of Power System Oscillations

In many power systems, equipment is installed to enhance various performance issues such as transient, oscillatory, or voltage stability (Kundur et al., 2004). In many instances, this equipment is power-electronic based, which generally means the device can be rapidly and continuously controlled. Examples of such equipment applied in the transmission system include a static Var compensator (SVC), static compensator (STATCOM), and thyristor-controlled series compensation (TCSC). To improve damping in a power system, a supplemental damping controller can be applied to the primary regulator of one of these transmission devices or to generator controls. The supplemental control action should modulate the output of a device in such a way as to affect power transfer such that damping is added to the power system swing modes of concern. This subsection provides an overview on some of the issues that affect the ability of damping controls to improve power system dynamic performance (CIGRE Technical Brochure No. 111, 1996; CIGRE Technical Brochure No. 116, 2000; Paserba et al., 1995; Levine, 1995).

9.4.1 Siting

Siting plays an important role in the ability of a device to stabilize a swing mode (Martins et al., 1990; Larsen et al., 1995; Pourbeik et al., 1996). Many controllable power system devices are sited based on issues unrelated to stabilizing the network (e.g., HVDC transmission and generators), and the only question is whether they can be utilized effectively as a stability aid. In other situations (e.g., SVC, STATCOM, TCSC, or other FACTS controllers), the equipment is installed primarily to help support the transmission system, and siting will be heavily influenced by its stabilizing potential. Device cost represents an important driving force in selecting a location. In general, there will be one location that makes optimum use of the controllability of a device. If the device is located at a different location, a device of larger size may be needed to achieve the desired stabilization objective. In some cases, overall costs may be minimized with nonoptimum locations of individual devices because other considerations must also be taken into account, such as land price and availability, environmental regulations, etc. (IEEE PES, 1996).

The inherent ability of a device to achieve a desired stabilization objective in a robust manner, while minimizing the risk of adverse interactions, is another consideration that can influence the siting decision. Most often, these other issues can be overcome by appropriate selection of input signals, signal filtering, and control design. This is not always possible, however, so these issues should be included in the decision-making process for choosing a site. For some applications, it will be desirable to apply the devices in a distributed manner. This approach helps maintain a more uniform voltage profile across the network, during both steady-state operation and after transient events. Greater security may also be possible with distributed devices because the overall system is more likely to tolerate the loss of one of the devices, but would likely come at a greater cost.

9.4.2 Control Objectives

Several aspects of control design and operation must be satisfied during both the transient and the steady-state operations of the power system, before and after a major disturbance. These aspects suggest that controls applied to the power system should

1. Survive the first few swings after a major system disturbance with some degree of safety. The safety factor is usually built into a Reliability Council's criteria (e.g., keeping voltages above some threshold during the swings).
2. Provide some minimum level of damping in the steady-state condition after a major disturbance (postcontingent operation). In addition to providing security for contingencies, some applications will require "ambient" damping to prevent spontaneous growth of oscillations in steady-state operation.

3. Minimize the potential for adverse side effects, which can be classified as follows:
 - a. Interactions with high-frequency phenomena on the power system, such as turbine-generator torsional vibrations and resonances in the AC transmission network.
 - b. Local instabilities within the bandwidth of the desired control action.
4. Be robust so that the control will meet its objectives for a wide range of operating conditions encountered in power system applications. The control should have minimal sensitivity to system operating conditions and component parameters since power systems operate over a wide range of operating conditions and there is often uncertainty in the simulation models used for evaluating performance. Also, the control should have minimum communication requirements.
5. Be highly dependable so that the control has a high probability of operating as expected when needed to help the power system. This suggests that the control should be testable in the field to ascertain that the device will act as expected should a contingency occur. This leads to the desire for the control response to be predictable. The security of system operations depends on knowing, with a reasonable certainty, what the various control elements will do in the event of a contingency.

9.4.3 Closed-Loop Control Design

Closed-loop control is utilized in many power-system components. Voltage regulators, either continuous or discrete, are commonplace on generator excitation systems, capacitor and reactor banks, tap-changing transformers, and SVCs. Modulation controls to enhance power system stability have been applied extensively to generator exciters and to HVDC, SVC, and TCSC systems. A notable advantage of closed-loop control is that stabilization objectives can often be met with less equipment and impact on the steady-state power flows than is generally possible with open-loop controls. While the behavior of the power system and its components is usually predictable by simulation, its nonlinear character and vast size lead to challenging demands on system planners and operating engineers. The experience and intuition of these engineers is generally more important to the overall successful operation of the power system than the many available, elegant control design techniques (Levine, 1995; CIGRE Technical Brochure, 2000; Pal and Chaudhuri, 2005).

Typically, a closed-loop controller is always active. One benefit of such a closed-loop control is ease of testing for proper operation on a continuous basis. In addition, once a controller is designed for the worst-case contingency, the chance of a less-severe contingency causing a system breakup is lower than if only open-loop controls are applied. Disadvantages of closed-loop control involve primarily the potential for adverse interactions. Another possible drawback is the need for small step sizes, or vernier control in the equipment, which will have some impact on cost. If communication is needed, this could also be a challenge. However, experience suggests that adequate performance should be attainable using only locally measurable signals.

One of the most critical steps in control design is to select an appropriate input signal. The other issues are to determine the input filtering and control algorithm and to assure attainment of the stabilization objectives in a robust manner with minimal risk of adverse side effects. The following subsections discuss design approaches for closed-loop stability controls, so that the potential benefits can be realized on the power system.

9.4.4 Input Signal Selection

The choice of using a local signal as an input to a stabilizing control function is based on several considerations.

1. The input signal must be sensitive to the swings on the machines and lines of interest. In other words, the swing modes of interest must be “observable” in the input signal selected. This is mandatory for the controller to provide a stabilizing influence.

2. The input signal should have as little sensitivity as possible to other swing modes on the power system. For example, for a transmission-line device, the control action will benefit only those modes that involve power swings on that particular line. If the input signal was also responsive to local swings within an area at one end of the line, then valuable control range would be wasted in responding to an oscillation that the damping device has little or no ability to control.
3. The input signal should have little or no sensitivity to its own output, in the absence of power swings. Similarly, there should be as little sensitivity to the action of other stabilizing controller outputs as possible. This decoupling minimizes the potential for local instabilities within the controller bandwidth (CIGRE Technical Brochure No. 116, 2000).

These considerations have been applied to a number of modulation control designs, which have eventually proven themselves in many actual applications (see Chapter 5 of CIGRE Technical Brochure No. 111 [1996]). For example, the application of PSS controls on generator excitation systems was the first such study that reached the conclusion that speed or power is the best input signal, with frequency of the generator substation voltage being an acceptable choice as well (Larsen and Swann, 1981; Kundur et al., 1989). For SVCs, the conclusion was that the magnitude of line current flowing past the SVC is the best choice (Larsen and Chow, 1987). For torsional damping controllers on HVDC systems, it was found that using the frequency of a synthesized voltage close to the internal voltage of the nearby generator, calculated with locally measured voltages and currents, is best (Piwko and Larsen, 1982). In the case of a series device in a transmission line (such as a TCSC), the considerations listed above lead to the conclusion that using frequency of a synthesized remote voltage to estimate the center-of-inertia of an area involved in a swing mode is a good choice (Levine, 1995). This allows the series device to behave like a damper across the AC line.

9.4.5 Input-Signal Filtering

To prevent interactions with phenomena outside the desired control bandwidth, low-pass and high-pass filterings must be used for the input signal. In certain applications, notch filtering is needed to prevent interactions with certain lightly damped resonances. This has been the case with SVCs interacting with AC network resonances and modulation controls interacting with generator torsional vibrations. On the low-frequency end, the high-pass filter must have enough attenuation to prevent excessive response during slow ramps of power, or during the long-term settling following a loss of generation or load. This filtering must be considered while designing the overall control as it will strongly affect performance and the potential for local instabilities within the control bandwidth. However, finalizing such filtering usually must wait until the design for performance is completed, after which the attenuation needed at specific frequencies can be determined. During the control design work, a reasonable approximation of these filters needs to be included. Experience suggests that a high-pass break near 0.05 Hz (3 s washout time constant) and a double low-pass break near 4 Hz (40 ms time constant), as shown in Fig. 9.3, are suitable for a starting point. A control design that provides adequate stabilization of the power system with these settings for the input filtering has a high probability of being adequate after the input filtering parameters are finalized.

9.4.6 Control Algorithm

Levine (1995), CIGRE Technical Brochure No. 116 (2000), and Pal and Chaudhuri (2005) present many control design methods that can be utilized to design supplemental controls for power systems. Generally, the control algorithm for damping leads to a transfer function that relates an input signals to a device output. This statement is the starting point for understanding how deviations in the control algorithm affect system performance.

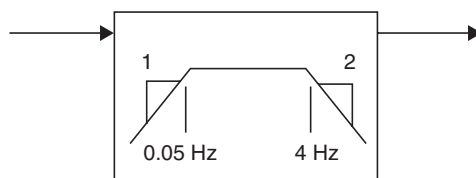


FIGURE 9.3 Initial input signal filtering.

In general, the transfer function of the control (and input-signal filtering) is most readily discussed in terms of its gain and phase relationship vs. frequency. A phase shift of 0° in the transfer function means that the output is proportional to the input and, for discussion purposes, is assumed to represent a pure damping effect on a lightly damped power swing mode. Phase lag in the transfer function (up to 90°) translates to a positive synchronizing effect, tending to increase the frequency of the swing mode when the control loop is closed. The damping effect will decrease with the sine of the phase lag. Beyond 90° , the damping effect will become negative. Conversely, phase lead is a desynchronizing influence and will decrease the frequency of the swing mode when the control loop is closed. Generally, the desynchronizing effect should be avoided. The preferred transfer function has between 0 and 45° of phase lag in the frequency range of the swing modes that the control is designed to damp.

9.4.7 Gain Selection

After the shape of the transfer function is designed to meet the desired control phase characteristics, the gain of the control is selected to obtain the desired level of damping. To maximize damping, the gain should be high enough to assure full utilization of the controlled device for the critical disturbances, but no higher, so that risks of adverse effects are minimized. Typically, the gain selection is done analytically with root-locus or Nyquist methods. However, the gain must ultimately be verified in the field ([see Chapter 8](#) of CIGRE Technical Brochure No. 111 [1996]).

9.4.8 Control Output Limits

The output of a damping control must be limited to prevent it from saturating the device being modulated. By saturating a controlled device, the purpose of the damping control would be defeated. As a general rule of thumb for damping, when a control is at its limits in the frequency range of interarea oscillations, the output of the controlled device should be just within its limits (Larsen and Swann, 1981).

9.4.9 Performance Evaluation

Good simulation tools are essential in applying damping controls to power transmission equipment for the purpose of system stabilization. The controls must be designed and tested for robustness with such tools. For many system operating conditions, the only feasible means of testing the system is by simulation, so confidence in the power system model is crucial. A typical large-scale power system model may contain up to 15,000 state variables or more. For design purposes, a reduced-order model of the power system is often desirable (Wang et al., 1997, Piwko et al., 1991). If the size of the study system is excessive, the large number of system variations and required parametric studies become tedious and prohibitively expensive for some linear analysis techniques and control design methods in general use today. A good understanding of the system performance can be obtained with a model that contains only the relevant dynamics for the problem under study. The key situations that establish the adequacy of controller performance and robustness can be identified from the reduced-order model, and then tested with the full-scale model. Note that CIGRE Technical Brochure No. 111 (1996), CIGRE Technical Brochure No. 116 (2000), and Kundur (1994), as well as Gibbard et al. (2001) and IEEE PES (2000, 2002, 2003, 2005) contain information on the application of linear analysis techniques for very-large systems.

Field testing is also an essential part of applying supplemental controls to power systems. Testing needs to be performed with the controller open-loop, comparing the measured response at its own input and the inputs of other planned controllers against the simulation models. Once these comparisons are acceptable, the system can be tested with the control loop closed. Again, the test results should have a reasonable correlation with the simulation program. Methods have been developed for performing such testing of the overall power system to provide benchmarks for validating the full-system model. Such testing can also be done on the simulation program to help arrive at the reduced-order models (Hauer,

1991; Kamwa et al., 1993) needed for the advanced control design methods (Levine, 1995; CIGRE Technical Brochure No. 116, 2000; Pal and Chaudhuri, 2005). Methods have also been developed to improve the modeling of individual components. These issues are discussed in great detail in [Chapters 6 and 8](#) of CIGRE Technical Brochure No. 111 (1996).

9.4.10 Adverse Side Effects

Historically in the power industry, each major advance in improving system performance has created some adverse side effects. For example, the addition of high-speed excitation systems over 40 years ago caused the destabilization known as the “hunting” mode of the generators. The fix was power system stabilizers, but it took over 10 years to learn how to tune them properly and there were some unpleasant surprises involving interactions with torsional vibrations on the turbine-generator shaft (Larsen and Swann, 1981).

The high-voltage *direct current* (HVDC) systems were also found to interact adversely with torsional vibrations (the subsynchronous torsional interaction [SSTI] problem), especially when augmented with supplemental modulation controls to damp power swings. Similar SSTI phenomena exist with SVCs, although to a lesser degree than with HVDC. Detailed study methods have since been established for designing systems with confidence that these effects will not cause trouble for normal operation (Piwko and Larsen, 1982; Bahrman et al., 1980). Another potential adverse side effect with SVC systems is that it can interact unfavorably with network resonances. This side effect caused a number of problems in the initial application of SVCs to transmission systems. Design methods now exist to deal with this phenomenon, and protective functions exist within SVC controls to prevent continuing exacerbation of an unstable condition (Larsen and Chow, 1987).

As the available technologies continue to evolve, such as the present industry focus on Flexible AC Transmission Systems (FACTS) (IEEE PES, 1996), new opportunities arise for power system performance improvement. FACTS controllers introduce capabilities that may be an order of magnitude greater than existing equipment applied for stability improvement. Therefore, it follows that there may be much more serious consequences if they fail to operate properly. Robust operation and noninteraction of controls for these FACTS devices are critically important for stability of the power system (CIGRE Technical Brochure No. 116, 2000; Clark et al., 1995).

9.5 Higher-Order Terms for Small-Signal Analysis

The implicit assumption in small-signal stability analysis is that the dynamic behavior of a power system in the neighborhood of an operating point of interest can be approximated by the response of a linear system.

This assumption has two important consequences; on the one hand, it allows for the application of powerful linear analysis methods that are well suited for the study of large systems; on the other hand, it limits the scope of the analysis to the region where the linear approximation is valid.

In certain cases, such as when a power system is stressed, it has been suggested that linear analysis techniques might not provide an accurate picture of the system modal characteristics (Vittal et al., 1991). Under these circumstances, techniques that extend the domain of applicability of small-signal stability analysis become an attractive possibility for advancing the understanding of power system dynamics. Of particular interest is the study of modes and modal interactions that result from the combination of the individual system modes of the linearized system. These modes and their interactions are termed “higher-order modes” and “higher-order modal interactions,” respectively.

The method of normal forms has been proposed as a means for studying higher-order modal interactions in power systems and several indices for quantifying higher-order modal characteristics have been introduced. (See Sanchez-Gasca et al., 2005 and references therein.) In general, the method of normal forms consists of a sequence of coordinate transformations aimed at removing terms of increasing order from a Taylor series expansion (Guckenheimer and Holmes, 1983). For power system

applications, due to the heavy computational burden associated with the computation of higher-order terms, work in this area has been focused on the Taylor series expansion evaluated up to second-order terms.

Provided that certain conditions are met, the method of Normal Forms allows for the system state variables to be written as a summation of exponential terms of the form $e^{\lambda_j t}$ and $e^{(\lambda_k + \lambda_l)t}$:

$$x_i(t) = \sum_{j=1}^n u_{ij} z_{j0} e^{\lambda_j t} + \sum_{j=1}^n u_{ij} \left[\sum_{k=1}^n \sum_{l=1}^n \frac{C_{kl}^j}{\lambda_k + \lambda_l - \lambda_j} z_{k0} z_{l0} e^{(\lambda_k + \lambda_l)t} \right] \quad (9.2)$$

λ_k , λ_l , and λ_j are the system modes, u_{ij} is an element of the matrix of right eigenvectors of the system state matrix (U), z_{j0} , z_{k0} , and z_{l0} are the initial conditions of transformed variables, and C_{kl}^j is the kl th element of the matrix C^j given by

$$C^j = \frac{1}{2} \sum_{p=1}^n v_{jp} [U^T H^p U] \quad (9.3)$$

In the above equation, v_{jp} is an element of the matrix of left eigenvectors of the system state matrix, and H^p is a Hessian matrix.

Most of the studies of power system electromechanical oscillations using the Normal Forms method are based on Eq. (9.2). This equation clearly shows the relation between the state variables $x_1, \dots, x_m$ the individual system modes $\lambda_1, \lambda_2, \dots, \lambda_m$ and the second-order modes, $\lambda_1 + \lambda_1, \lambda_1 + \lambda_2, \dots, \lambda_{n-l} + \lambda_m, \lambda_n + \lambda_n$. The terms associated with the mode pairs $\lambda_k + \lambda_l$ provide information not available from the linear approximation of the power system equations. These terms represent “modal interactions” that arise due to the presence of the higher-order terms. The coefficients of the exponential terms $e^{(\lambda_k + \lambda_l)t}$ give a measure of the participation of the mode combination $\lambda_k + \lambda_l$ in a given state variable.

Several quantitative indices have been developed based on the Normal Form analysis for quantifying the degree of modal interactions. These indices provide information regarding the interacting modes, the states participating in these modes, and the degree of the nonlinear interaction (Sanchez-Gasca et al., 2005).

The computational burden of the Normal Form analysis is large. Inclusion of even second-order terms for a large system represents a significant computational burden. Techniques need to be developed to reduce the computational burden.

A related method also aimed at the study of higher-order modal interactions is described in Shanechi et al. (2003).

9.6 Summary

In summary, this chapter on small signal stability and power system oscillations shows that power systems contain many modes of oscillation due to a variety of interactions among components. Many of the oscillations are due to synchronous generator rotors swinging relative to one another. The electromechanical modes involving these masses usually occur in the frequency range of 0.1–2 Hz. Particularly troublesome are the interarea oscillations, which are typically in the frequency range of 0.1–1 Hz. The interarea modes are usually associated with groups of machines swinging relative to other groups across a relatively weak transmission path. The higher-frequency electromechanical modes (1–2 Hz) typically involve one or two generators swinging against the rest of the power system or electrically close machines swinging against each other.

These oscillatory dynamics can be aggravated and stimulated through a number of mechanisms. Heavy power transfers, in particular, can create interarea oscillation problems that constrain system operation. The oscillations themselves may be triggered through some event or disturbance on the

power system or by shifting the system operating point across some steady-state stability boundary, where growing oscillations may be spontaneously created. Controller proliferation makes such boundaries increasingly difficult to anticipate. Once started, the oscillations often grow in magnitude over the span of many seconds. These oscillations may persist for many minutes and be limited in amplitude only by system nonlinearities. In some cases they cause large generator groups to lose synchronism where a part of or the entire electrical network is lost. The same effect can be reached through slow-cascading outages when the oscillations are strong and persistent enough to cause uncoordinated automatic disconnection of key generators or loads. Sustained oscillations can disrupt the power system in other ways, even when they do not produce network separation or loss of resources. For example, power swings, which are not always troublesome in themselves, may have associated voltage or frequency swings that are unacceptable. Such concerns can limit power transfer even when oscillatory stability is not a direct concern.

Information presented in this chapter addressing power system oscillations included:

- Nature of oscillations
- Criteria for damping
- Study procedure
- Mitigation of oscillations by control
- Higher-order terms for small-signal stability

As to the priority of selecting devices and controls to be applied for the purpose of damping power system oscillations, the following summarizing remarks can be made:

1. Carefully tuned power system stabilizers (PSS) on the major generating units affected by the oscillations should be considered first. This is because of the effectiveness and relatively low cost of PSSs.
2. Supplemental controls added to devices installed for other reasons should be considered second. Examples include HVDC installed for the primary purpose of long-distance transmission or power exchange between asynchronous regions and SVC installed for the primary purpose of dynamic voltage support.
3. Augmentation of fixed or mechanically switched equipment with power-electronics, including damping controls can be considered third. Examples include augmenting existing series capacitors with a thyristor-controlled portion (TCSC).
4. The fourth priority for consideration is the addition of a new device in the power system for the primary purpose of damping.

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